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# Impact of unpredictable renewables on gas-balancing design in Europe

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*Abstract* – The gas system in Europe is facing increasing unpredictability due to the interactions with the electricity generation system. Indeed, gas fired power plants make up an important back-up technology to deal with intermittency induced by wind-power integration. Therefore, the flexibility needs with respect to unpredictable power generation are actually transferred to the gas market. Applying the well-known electric power generation concepts of 'unit commitment' and 'dispatching' to the gas market, a hypothetical gas-transmission system has been modeled to verify, first, the physical impact of wind power forecasting errors on the gas system, and, second, its effect on the organization of gas-imbalance settlement for non-market-based and market-based design options. Increasing unpredictability leads to more expensive physical balancing of the gas system. These costs should be borne as much as possible by those effectively causing them. From a regulatory point of view in the European context, cost recovery by means of non-market-based settlement faces the problem of defining an appropriate cost-neutral penalty that covers the balancing costs and incentivizes shippers. Market-based settlement relates the variable imbalance tariffs to the actual system imbalance and thus any factor that strongly impacts on the system state like unpredictability. However, this mechanism raises imbalance-settlement tariffs for all unbalanced gas network users, even if the major source of unpredictability is a clearly identifiable shipper.

*Keywords* – gas balancing; gas-market regulation; wind power intermittency; gas system optimization

## 1. Introduction

The gas system and electricity-generation system are interacting due to the use of gas-fired power plants, but also more and more because these plants are used to balance the electricity system. This interaction is expected to further increase in the future. The gas system, then, has to deal with this changing context: gas is storable, but physical and organizational challenges remain present in the balancing of the gas network. This paper discusses this overlooked problem in the literature on gas regulation, which is of particular interest in Europe today, and even more so in the next decades, because the organization of gas balancing is still under much debate. The main research question is how this new kind of unpredictability in the gas system interacts with possible organizational designs of a gas-balancing mechanism in the European context. Towards this aim, the physical impact of balancing with gas is looked at in a conceptual case study that presupposes the balancing of wind-power output by gas-fired power, disregarding and thus excluding other balancing tools in the electricity-generation system. By using an operations research model, the physical impact on the gas system is simulated and the associated costs are calculated. Finally, these costs have to be passed on to unbalanced shippers. Note that the case study is conceptual and that the conclusions are therefore qualitative, and are not relating to a particular existing energy system.

The investigated problem basically originates in the large-scale introduction of renewable-energy sources (RES) in the electricity system. The roll-out of these RES affects the electricity-generation system [1] and required grid [2], but also have an impact on the role of other energy carriers such as natural gas (which can accommodate this RES roll-out). Wind power has an intermittent character, meaning the output is variable and to some extent unpredictable [3]. Furthermore, wind power has zero marginal costs and as such replaces other, dispatchable electric power plants in the dispatching order when generating [4, 5]. Thus, electricity balancing tools are required to deal with this wind-power intermittency [1]. Possible balancing tools consist of pump-hydro storages, demand-side responsiveness and flexibly dispatchable conventional power plants, such as gas-fired electric power generation (GFPP). Lower investment cost, favorable $CO_2$-emission characteristics, flexible operability and a relatively short lead time between final investment decision and actual operation of a plant make, e.g., open-cycle gas turbines (OCGT) and combined-cycle gas turbines (CCGT) attractive technology [6-9].[1] Current high fuel prices in Europe represent a downside of GFPP technology, but the worldwide development of shale gas and the LNG market may change this. Furthermore, the inclusion of $CO_2$ prices improves the relative fuel cost compared to, e.g., coal-fired electric power plants.

As an example, Figure 1 shows the day-ahead forecast of wind power, together with the actual wind-power output for the year 2012 for the Belgian system, which has approximately 1000 MW installed wind-power capacity, to illustrate both the variable and unpredictable character.

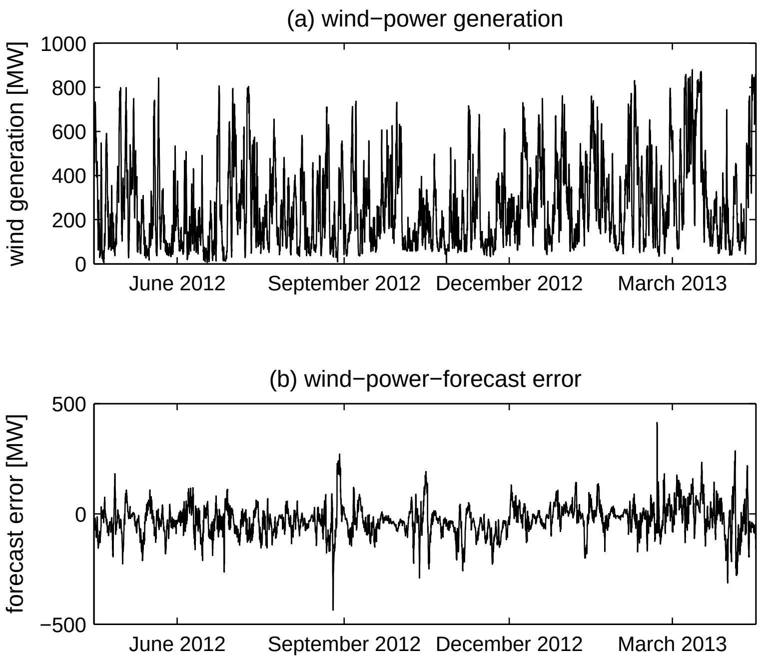


**Figure 1. (a) Wind-power output and (b) wind-power-forecast error, for the period May 1, 2012 – April 30, 2013, for Belgium. A positive forecast error indicates an overestimation (forecast higher than actual value), whereas a negative error indicates an underestimation (forecast lower than actual output). Data obtained from Elia [10].**

When gas-fired power plants are used for balancing, the flexibility needs of the electricity-generation system are (partly) transferred to the gas system, imposing a need to allocate system-flexibility costs to the users thereof. Gas-Balancing-responsible shippers can rely on the *ex-post* balancing services provided by the gas TSO (transmission-system operator) or they can take measures to contract *ex-ante* flexibility services [11]. Pivotal to this choice are the gas-balancing rules that have to allocate the system costs to the unbalanced party, on the one hand; and incentivize shippers to balance beforehand, on the other hand. The addition of

[1] Open-cycle gas turbines (OCGT) are actually providing more dispatching flexibility as that technology allows even higher ramping rates than CCGTs. However, for the conceptual analysis in this paper, CCGTs have been chosen arbitrarily as the considered GFPP technology.

wind power and its interaction with mainly GFPPs changes the gas-demand characteristics. It will be demonstrated that some current balancing-mechanism designs become impractical (and on the long term perhaps unsustainable) to deal with this changing gas demand.

The role of gas and wind in the power-generation mix has been underlined many times in the literature on the operation of electricity systems. Delarue et al. [12] have demonstrated that for electricity systems with a diverse generation mix, wind power mainly interacts with GFPPs. The Spanish electricity system with its massive amount of wind power has been shown to strongly rely on CCGT-related flexibility to deal with rising electricity-generation volatility [13]. The expected impact of large-scale wind-power integration on the UK gas network has been found to come down to more CCGTs operated in a flexible way and results in substantial line-pack swings, more gas-compression-power consumption and more overall gas use for electric power generation [14]. Furthermore, concerns are raised in that study by Qadrdan et al. [14] regarding very rapid depletion of the line-pack buffer if the “wrong” circumstances occur: a combination of low wind-power output, peak electrical gas demand and peak non-electrical gas demand. In a way, massive wind power is crowding out other electricity-generation technologies in favor of more flexible gas in terms of new capacity added (MW). Moreover, long stretches of cold weather, and thus high heating demand, often coincide with periods of low wind speeds. The effective number of operating hours of CCGTs, and thus the number of MWh produced per year , on the other hand, is said to rise by some studies, e.g., [8], whereas other studies argue the effective running hours of CCGTs, or GFPPs in general, will go down, e.g., [9]. Nevertheless, gas’ qualification as “fuel of consequence” seems justified.

Concerns about the changing interactions between gas and electricity have also been raised before in the literature. Hallack [15] extensively discusses the changing needs of the gas network imposed by the new demand characteristics of increasing gas-fired electric power. In the new gas market, short-term flexibility, exchangeability and storability (for short periods) are the keywords and the regulatory framework for gas-infrastructure development has to respond to these needs. The French regulator also has raised concerns about the surge of GFPPs, especially in the field of daily balancing of the gas loads [16, 17]. Indeed, the balancing of gas supply and demand on an hourly and daily basis becomes more challenging because the flexible dispatching of GFPPs coincides with strongly varying gas needs: when ramping up a CCGT, gas withdrawal soars instantly, whereas the ramping down requires gas flows to drop almost instantly. Evidently, the management of pressure in the pipelines can deliver the needed flexibility. Yet, pipeline-based flexibility is limited in volume and can only be used for short-term storage [11]. The deployment of line-pack flexibility is not limited to a specific kind of gas demand, but evidence from the UK suggests that flexible CCGTs cause higher swings in the line pack, defined as the amplitude between the maximal and minimal line-pack level over a gas day, than the residential sector [11, 18, 19]. This was not perceived as very troublesome because the share of electric power generation in the European gas demand has been relatively low. Germany, Italy and Spain, however, show a remarkable growth of gas consumption in the electric power sector over the last decade [20, 21]. Although smaller in absolute numbers, a similar trend can be observed in the other European countries as well, the exception being the UK, which remained more or less stable because its “dash for gas” already started in the late 80s and early 90s [22]. Moreover, power generation is projected to remain the main driver of growth in future (European) gas demand [6, 7]. Consequently, the short-term gas-flexibility needs of the electric power sector will become a significant issue.

The regulation of gas balancing has mostly been studied in the industry literature in Europe. The regulators have published viewpoint papers, consultation papers and framework guidelines on how to organize settlement of imbalances [23-28]. The transmission-system operators and shippers have also contributed to the debate [29-34]. The main outcome of this debate regarding settlement design comes down to applying market-based settlement and to have cost-neutral imbalances tariffs that just pass on the TSO’s effective balancing costs to unbalanced shippers. However, in practice, most balancing is still non-market based, as indicated by KEMA [35]. The organization of balancing has further been discussed by Lapuerta [36] concerning the time interval over which balancing should occur. In that work it is said that a daily balancing interval is not increasing security risks for the gas-flow programs at that time in the UK. The contributions in the academic literature to the balancing debate are limited. There are two reasons for this: first, the organization of balancing became an issue only after the liberalization and unbundling; second, the problem is specific to the European institutional context. Indeed, in Europe, the gas network is organized as a zone consisting of multiple connected pipelines. In that zone, time and geographical flexibility are offered on a non-discriminatory basis, meaning that flexibility is bundled and (partly) socialized. Hence, the regulation and organization of gas balancing should be investigated. Especially, in a gas market that is evolving rapidly because of the above mentioned environmental, technical and economic challenges.

This paper, then, looks at a particular problem of gas balancing: the challenges of a new kind of unpredictability that is transferred from the electricity-generation system. The effect of wind-power intermittency on the (isolated) electricity system has been studied extensively, e.g., [37-40], but the impact of integration of these intermittent RES on the load balancing of the gas system, or any other interacting energy system, is less or not studied. The impact on the gas system is twofold: a physical impact, which has been identified by Qadrdan et al. [14], and a regulatory or organizational impact, which has not been studied before to the best of our knowledge, and which is the core subject of this paper. Indeed, the economic settlement of the physical and contractual imbalances poses a regulatory challenge that can be dealt with either according to a market-based mechanism or according to a non-market-based mechanism. Both organizational options will be examined below for increasing unpredictability of gas demand, applying the electricity-generation concepts "unit commitment" and "power dispatching" to the gas system. The former concept deals with the planning of the power plants before real time with imperfect information, whereas the latter refers to the actual use of power plants in the real time when more information has become available. These concepts are then translated into a gas commitment, meaning an amount of gas that is planned to be used, and gas dispatching, meaning the actual amount of gas that is required to meet demand.

The paper is further organized as follows. The methodology and assumptions of the case study are discussed in the subsequent section. Section 3 presents the results on the physical impact on gas balancing in the assumed gas system. The organization of gas-imbalance settlement and its response to the rising unpredictability is discussed in section 4. The main findings and conclusions are then summarized and discussed in a final section.

## 2. Conceptual case study: description of methodology and assumptions

To study the conceptual impact of wind-power unpredictability (forecast errors) on the balancing of the gas network, a simplified hypothetical electricity and gas system is considered with wind participation levels between 15 and 25 percent of generated electricity. An example of an applied case study on the operational impact of massive wind-power integration in the (predicted) future UK system can be found in [14]. In that study by Qadrdan et al., it is shown that gas-network operations and the electricity-generation mix are affected by the interactions between wind and gas for electric power generation. The conceptual study in this paper looks beyond that operational impact, and focuses on the impact of wind-power unpredictability on the (design of) gas-balancing mechanism.

An operations research model, GASFLEX [41], is used to simulate the gas system with regard to its physical impact due to shipper imbalances and the costs associated with this imbalance. This hypothetical gas system is discussed in more detail in section 2.2. The unpredictability is introduced as five deterministic scenarios with regard to the electricity produced by GFPPs. To this end, a hypothetical electricity system has been simulated with the MILP-OPEG model by Delarue [42] taking into account a forecast error. This is further explained in subsection 2.1. We do note that the electricity system is simplified and tailored to the needs of the problem under investigation, which is the gas system. Therefore, the electricity related data below are to be considered input for the simulation of the gas system. Finally, subsection 2.3 summarizes the complete problem statement.

### 2.1 Electricity-system input for gas system: assumptions and data

The assumed electricity-generation system consists of 600 MW wind power in a single wind farm and four CCGT plants of 400 MW each. All CCGT plants are identical with respect to their characteristics, e.g., for minimum uptimes and downtimes and efficiency rates at different working points.[2] No electrical network is taken into account, as the relevant object of study is the gas system and the effects of the production of electric power on it. For this same reason, this very simple two-technology electricity-generation system is sufficient.

A scaled generic electricity-demand profile for a typical day in Northwest Europe serves as the exogenous input for the power-plant unit-commitment and power-dispatching optimization [42]. The average electric-power demand amounts to 1370 MW with a fairly limited variability of the power-demand profile as measured by its standard deviation of 118.8 MW. Wind power is then taken into account by subtracting it from the considered electricity-demand profile, which gives the net electric power demand to be met by CCGTs. The unpredictable fluctuations of wind power are accounted for by imposing four deterministic wind-power forecast-error profiles on the real-time wind-power output profile, which is the same in all examined cases.[3] In other words, the variability of wind is the same in all cases and is rather small; hence, the wind-power profile is rather flat in the perfect-forecast case. The differences between profiles depend on the unpredictable fluctuations. It is the effect of these fluctuations on the gas-system balancing that is of interest in this study. Additionally, a no-wind scenario serves as benchmark to understand the flexibility needs with and without wind. With reference to the electric power demand, demand-side uncertainty is disregarded to simplify the analysis. The 0 MW-wind scenario should therefore return similar outcomes to the perfect-forecast scenario because in both scenarios wind is equally reliable as gas at the supply side. All remaining differences between the perfect-forecast case and the no-wind case, e.g., with regard to intra-day flexibility, can be attributed to differences in variability.

**Table 1. Summary of examined wind-power scenarios based on different forecast errors for wind-power output and a benchmark scenario with no wind: μ represents the average, and σ the standard deviation, of predicted electric power generation by CCGTs**

| Scenario | Description | μ [MW] | σ [MW] |
|---|---|---|---|
| perfect forecast | wind-power output is predicted perfectly and dispatching follows unit commitment | 1100 | 106.4 |
| small errors | small prediction errors require some corrective dispatching decisions | 1099 | 98.44 |
| overestimation | actual wind-power output much less than predicted and more CCGT power needs to be dispatched | 1063 | 194.9 |
| underestimation | actual wind power output exceeds predictions requiring CCGTs to be regulated down | 1141 | 99.86 |
| no wind | benchmark with zero wind-power output | 1370 | 118.8 |

Table 1 provides an overview of the wind-power scenarios that are examined. The average predicted electric power to be generated by CCGTs and the variability of the predicted gas-fired electric power generation are reported under μ (MW) and σ (MW), respectively.

Table 2, then, summarizes the average and the standard deviation of the wind-power prediction errors for the four forecast scenarios. E.g., in the overestimation case, 37 MW of predicted wind power was not actually available during the dispatching phase. Note that the errors should be compared to the 600 MW of installed wind-power capacity.

[2] A priority rule is applied whenever multiple optimal dispatching solutions exist: in that case plants could be substituted at zero cost and the obtained solution would otherwise depend on the solution path of the algorithm.
[3] Wind power profiles are derived from wind-power data published by the Belgian electricity-transmission-system operator, Elia [43], and prediction errors have been generated according to the method introduced by Brand en Kok [44] and have been calibrated on historical forecast and real-time wind-speed data of the Royal Dutch Meteorological Institute [45].

**Table 2. Summary of wind-power prediction statistics for the four scenarios: mean prediction error [MW] and standard deviation of the prediction error [MW] for 600 MW installed wind-power capacity; actual output compared to predicted output**

| Scenario | Mean prediction error [MW] | St.dev. prediction error [MW] |
|---|---|---|
| perfect forecast | 0 | 0 |
| small errors | -1.5 | 16.7 |
| overestimation | -37 | 107 |
| underestimation | 40 | 31.4 |

Note that the naming of the research cases refers to the wind-power forecast: the underestimation case underestimates wind (too little wind output predicted), but coincides with overestimating gas demand (too much gas committed).

Figure 2 plots the total electricity demand and the forecasted residual gas-fired electric power demand in the upper panel, whereas in the lower panel the wind-power forecasts are illustrated.

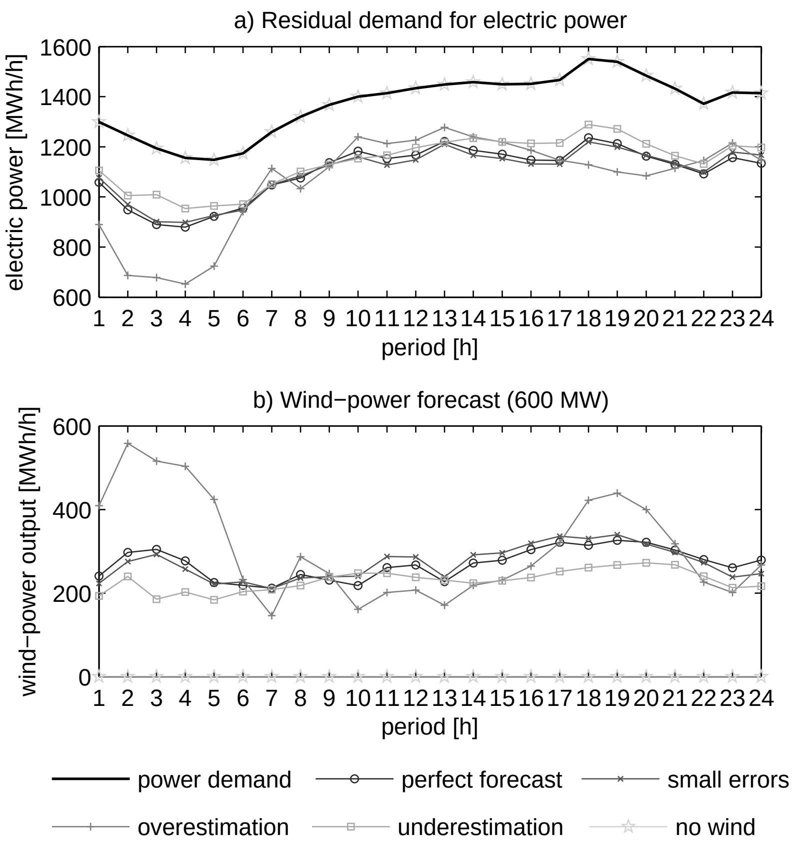


**Figure 2. Electric power profiles – a) forecasted residual demand for electric power generation by CCGTs and b) wind-power-output forecasts for different forecast qualities; total electric power demand is represented in the upper panel by the black line**

The average predicted wind-power output is obtained by subtracting the average predicted CCGT production (represented by "μ" in Table 1) from the average electric power demand (1370 MW). It varies between approximately 230 MW or about 17 percent of the average electric-power demand, and 310 MW or 22 percent of the average electric-power demand. The large standard deviation ("σ" in Table 1) for the scenario with overestimated wind power (third scenario in Table 1) indicates a forecast with much more variable wind power than will actually occur in real time.

During the first 8 hours, for instance, much more wind-power output is predicted than actual wind output will be, as can be observed in the difference between the overestimation case and the perfect-forecast case. Furthermore, the electric-power-demand profile and the no-wind profile provide the same information, hence their overlap in Figure 2.a.

For the optimization details, we refer explicitly to the original work by Delarue [42], in which the operation of power plants is optimized in a two-step process. In the first step, a unit-commitment (UC) problem is solved for the electricity-generation system based on the forecasted wind power and the resulting net demand for gas-fired power generation. The second part of the optimization deals with the actual economic power dispatching (PD) of the CCGTs based on the actual hourly wind-power output and the CCGT costs.

In order to investigate the flexibility of the gas network, the hourly electric power production of the CCGTs (MW) is translated into an hourly gas-flow rate (expressed in million cubic meters per hour, $M.m^3$) by using the power plant's efficiency rate and an assumed gross caloric value (GCV) of 0.0115 $MWh/m^3$ for gas. The output of this electricity-generation optimization is now used as input for the gas-system optimizations that are discussed in the subsequent section.

**2.2 Hypothetical gas system: assumptions and data**

The hypothetical gas-pipeline system, illustrated in Figure 3, consists of five demand nodes divided over four CCGT plants and one industrial consumer. Next, gas enters the network through two production/import nodes, supply A and supply B, and one storage site can be used to inject and withdraw gas. The nodes are connected by seven pipelines without gas compression (thus, compression occurs outside the modeled system). Pipelines are defined in forward direction, but can allow backward flow. In Figure 3, for instance, the flow on line CCGT2 – storage physically flows from the storage to CCGT2, hence the negative sign. Furthermore, the figure illustrates supply and demand (**bold**, $M.m^3/h$) and pipeline inflow and outflow rates (*italic*, $M.m^3/h$) for the $6^{th}$ hour of the overestimation case. All supply from node B (0.0875) is injected in line B – CCGT3 (*0.0875*), but less gas is taken from the line (*0.0771*). As a result, the line-pack buffer of that pipeline is loaded. Part of the gas is used to meet local demand of CCGT3, whereas the remaining gas is injected on the connecting pipelines industry – CCGT3 and CCGT3 – CCGT4. Other numbers and nodal and line balances are explained similarly. More technical details (e.g., pressure limits and pipeline geometry) are provided in an Appendix. Details on the modeling can be found in [41], but the main principles are discussed below.

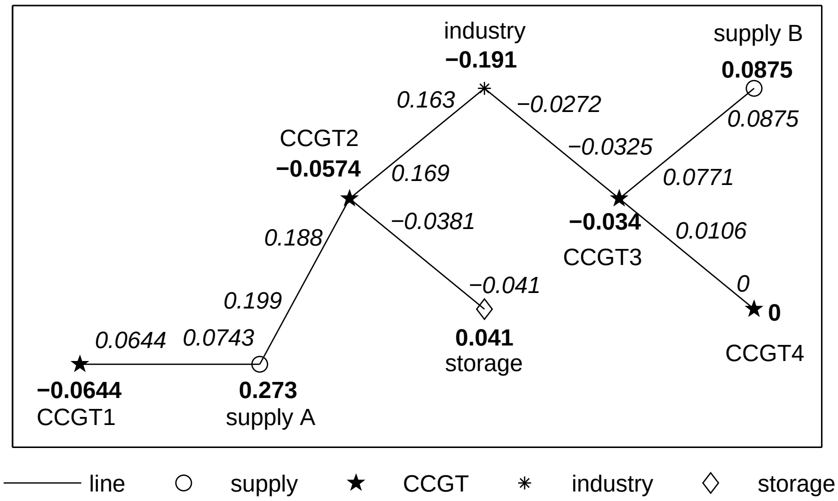


**Figure 3. Gas network with 2 gas-supply nodes (o), 1 storage node (◊), 1 industrial-demand (*) node and 4 CCGT-demand nodes (★) – numbers [M.m$^3$/h] for the 6$^{th}$ hour of the overestimation case, italic numbers represent flows in and out of a pipeline with negative numbers indicating backward flow, numbers in** bold **indicate supply and demand (including storage)**

As explained by Keyaerts et al. [11], the pipeline capacity offers time-flexibility services at the cost of reducing transport services. In other words, capacity must be designed taking into account a peak-flow service and a peak-flexibility service. The connecting pipelines in our hypothetical gas system, therefore, have been defined in terms of pressure limits and diameter in such a way that the pipeline capacity does not limit the flow rates demanded by the CCGTs.

The line-pack flexibility provides time flexibility (contrasted with geographic flexibility) to the TSO, the kind of flexibility needed to deal with sudden changes like intermittent gas demand. [4] This pipeline storage is expressed in M.m$^3$. Underground storage makes up a second source of system flexibility in the hypothetical gas system. Balance between injection, withdrawal and storage level has to be maintained over time.

On the shippers' side, the gas-supply contract is assumed not to provide intra-day modulation and other *ex-ante* flexibility is disregarded to focus on *ex-post* balancing. As a consequence of these assumptions, all flexibility to deal with unpredictable fluctuations has to come from the TSO. And the shipper optimization can only use *ex-post* flexibility to modulate supply to match (predicted) demand.

A flow-balance equation ensures that all gas entering the system (supply, withdrawal from storage or depletion of line pack) equals the gas leaving the system (demand, injection in storage, buffering as line pack). The objective of the model is to minimize the total system-balancing costs. To this end, an operational cost of 0.01 EUR/m$^3$ has been considered with regard to pipeline storage and 0.05 EUR/m$^3$ for traditional storage. These costs have been based on flexibility cost data published by the Dutch TSO [46].

The optimization with GASFLEX is first conducted for the committed CCGT plants in every hour based on the wind-power prediction (this is the gas "unit commitment"). Subsequently, the actual hourly gas dispatch is optimized taking into account wind-forecast inaccuracies for the CCGT gas demand (the gas "power dispatching"). In that second phase, the gas supply at the import nodes is fixed at the flat levels committed in

[4] Geographic flexibility refers to routing options for gas: gas molecules are homogenous and the network operator will optimize gas flows independent of shipper nominations. Therefore, shippers can enter gas in one part of the gas system to take it off in another part of the system and they can change these locations according to their needs, within the physical constraints of the gas system. Time flexibility, on the other hand, allows gas entering at time $t$ to be used at time $t+x$.

the UC. Indeed, this supply fixing simulates the unpredictability of gas demand that is dependent on the wind-power forecast error. Therefore, the obtained imbalances can be considered exogenous to the dispatching phase. It is possible to consider re-nominations to some extent, e.g., up to two hours before real time, as better short-term wind-speed forecasts become available. Such an approach lowers the financial balancing needs if a shipper can use *ex-ante* flexibility on short notice. However, this option has not been implemented here because the fundamental dynamics would not change. It is important to understand that when, e.g., storage is used as ex-ante flexibility, the contractual flows (rights to gas) and the physical injection or withdrawal are separate matters with different actors responsible for either of them. In fact, only the net storage flow has to be physically injected or withdrawn by the end of the day.

**2.3 Problem setting: further details**

The hypothetical problem setting further consist of two shippers of about equal size in total demand over the horizon: a shipper with just CCGTs in his demand portfolio, hereafter "wind shipper", and a shipper with an industrial-demand profile, hereafter "historic shipper". With regard to the physical balancing of the system, the TSO has access to line-pack flexibility and underground storage.

Balancing costs have to be recovered from unbalanced shippers through the settlement mechanism. Two distinct design options are examined: a non-market-based mechanism and a market-based mechanism. The former stands for a design in which an imbalance is cashed out at a price that is determined disregarding the imbalance position of the gas system. By definition, for non-market-based settlement, the imbalance fee ($F_{imb}$) is independent of the system imbalance ($imb_{sys}$):

$$\frac{\partial F_{imb}}{\partial imb_{sys}} = 0 \qquad (1)$$

A market-based mechanism, on the other hand, implicitly or explicitly links the imbalance fee to the system imbalance or the TSO's deployment of flexible gas as expressed by the non-zero derivative of the imbalance tariff to the system imbalance in Eq. (2):

$$\frac{\partial F_{imb}}{\partial imb_{sys}} \neq 0 \qquad (2)$$

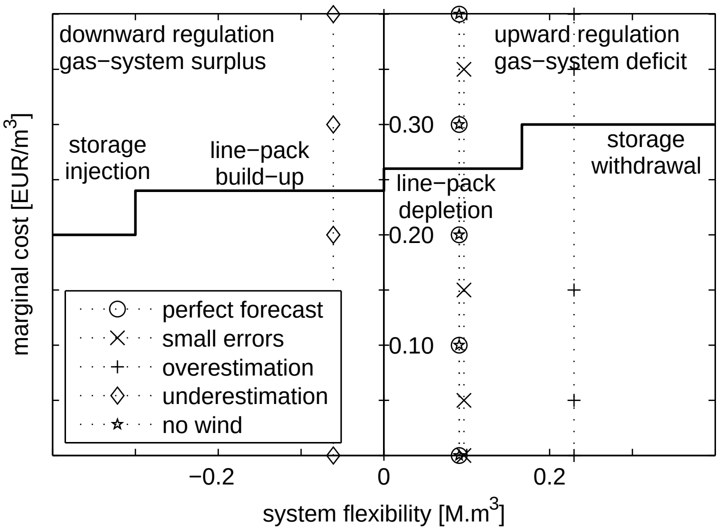


**Figure 4. Merit-order curve for system flexibility for five wind-power scenarios when the historic shipper is short: upward (downward) regulation to correct gas-system deficit (surplus), the system-imbalance lines determine the effective marginal cost of system flexibility; the "no-wind" and "perfect-forecast" lines overlap**

Figure 4 illustrates the dynamics behind this market-based settlement of *ex-post*-balancing services. The TSO can dispatch an amount of upward or downward flexibility to correct for a gas system in deficit or in surplus, respectively. The sources of flexibility are ranked according to their marginal costs and the cheapest sources are used first. Only if additional flexibility is required, more expensive flexible gas is used. The imbalance tariff per unit of imbalance, then, can be related to the system imbalance and the cost of the marginal unit of system flexibility. In Figure 4, the gas reference price is assumed to be 0.25 EUR/m$^3$. An operational cost for flexibility (*supra*) has to be added to, or subtracted from the reference price, e.g., the day-ahead price, for gas to obtain the marginal cost of flexible gas.

However, the merit-order curve is dependent on the actual gas-system operation because availability and dispatching of line-pack flexibility is only determined dynamically within GASFLEX. Therefore, Figure 4 only shows one possible merit curve that is obtained from the optimization. The dynamic limit for upward line-pack flexibility amounted to approximately 0.17 M.m$^3$ or about 50 percent of total hourly demand or 2 percent of total daily demand. Furthermore, Figure 4 shows the gas-system imbalances for the five examined cases from Table 1. The lines indicating the no-wind and the perfect-forecast cases coincide almost perfectly because the wind-power output is perfectly predicted in the UC stage in both cases and the remaining intra-day variability is small and very similar. Note that line-pack flexibility has been included in the merit order; whereas in practice, line-pack flexibility is must-use flexibility that is subtracted from the TSO demand for flexibility to obtain the residual demand for flexible gas that has to be procured from balancing-services providers. A single reference price is assumed for all actors, disregarding the strategic use of the balancing mechanism by shippers to, e.g., dump cheap gas from long-term contracts capitalizing on a large reference-price difference.[5]

Ultimately, only four situations can occur for end-of-period imbalance settlement (Table 3).

**Table 3. Settlement mechanism: four distinct quadrants according to individual shipper imbalance and system imbalance**

| Shipper imbalance | System imbalance | |
|---|---|---|
| | Short | Long |
| Short | Q1 | Q3 |
| Long | Q2 | Q4 |

First, an individual shipper can be short when the system is also short (Q1 in Table 3). In that case the shipper is instigating the system imbalance. Another shipper can be long when the system is short (Q2 in Table 3). That shipper actually mitigates the system imbalance When the system is long, short shippers will be settled according to Q3. Finally, Q4 represents the applicable imbalance tariff for long shippers in a long system. Each quadrant, thus, represents a system-shipper combination with a distinctive imbalance tariff. However, most currently applied settlement mechanisms have no connection between the system position and the applicable tariff, using the same for both situations (Q1 = Q3 and Q2 = Q4).

Several options exist to determine tariffs from the merit-order curve and the system imbalance. The most basic example consists in using the price coinciding with the used amount of balancing energy for both long and short shippers. The underestimation case in Figure 4, for instance, has a marginal cost of 0.24 EUR/m$^3$ for system flexibility (or net cost of 0.01 EUR/m$^3$ when the reference price of gas is taken into account. This kind of tariff system rewards shippers that help the system with a mitigating opposing imbalance position, whereas it penalizes shippers who further instigate the system imbalance.

[5] If the shipper's contract price amounts to 0.18 EUR/m$^3$ and the balancing reference price is 0.25 EUR/m$^3$, the shipper can dump gas in the balancing mechanism even taking into account net imbalance charges of, e.g., 20 %; this is especially true for non-market-based balancing because the charges are in that case independent from the state of the system.

So, market-based settlement depends on an implicit or explicit merit-order curve for flexible gas. The merit-order-derived marginal cost of balancing, then, provides better signals to the market players with reference to the real costs of flexibility and the need for further investment in these instruments. A non-market-based tariff, on the other hand, does not take into account the overall state of the gas system and the actually used flexibility. Therefore, this settlement design does not provide efficient signals.

Actual settlement mechanisms can become very complex. The subsequent analysis of wind-power unpredictability on gas balancing does not include complex settlement designs, but rather uses basic settlement designs to understand the fundamental principles. The main findings, though, remain valid for more complex designs because the latter are just combinations of the basic design options that are examined.

## 3. Effects of wind unpredictability on gas balancing

The impact assessment of wind-power unpredictability on gas balancing is split in two parts. The first subsection deals with the impact of unpredictability on the physical flexibility requirements of the gas system. The cost recovery by means of the settlement mechanism is subject of a second subsection.

### 3.1 Physical gas balancing

Because of prediction errors, the wind shipper commits too much or too little gas during the UC, resulting in unavoidable imbalances in the dispatching phase. This wind-shipper imbalance is combined with the imbalance of the historic shipper, for whom both negative and positive forecast errors have been assumed. The TSO, then, anticipates the (intra-day) flexibility needs based on the information received during the UC, e.g., building up a buffer when shippers expect to be short during the day.

#### a. Historic shipper: short imbalance position

Table 4 gives an overview of the dispatched flexibility on a net daily basis (end-of-day flexibility). Note that negative numbers indicate that gas is withdrawn from the line-pack or the storage (upward flexibility), whereas positive numbers indicate an increase of the buffered gas in the pipeline or in the underground storage.

**Table 4. Dispatching of flexibility (daily net amount $M.m^3$) assuming a short historic shipper; positive: line-pack buffer / storage inflates; negative: line-pack buffer / storage decreases**

| | Perfect forecast | Small error | Over-estimation | Under-estimation | No wind |
|---|---|---|---|---|---|
| Line pack [$M.m^3$] | -0.091 | -0.097 | -0.176 | 0.061 | -0.091 |
| Storage [$M.m^3$] | 0 | 0 | -0.054 | 0 | 0 |

If insufficient gas is supplied because forecasts indicated low gas demand, the buffers are called upon to provide flexibility. This is the case for the first three forecast scenarios and the no-wind scenario of Table 4. The underestimation case (column 4 in Table 4), on the other hand, results in a net surplus of gas because the wind-shipper surplus exceeds the deficit of the historic shipper. In this scenario, the opposing imbalance positions actually help the overall system.

The net system-balancing costs are displayed in Figure 5. These net balancing cost are obtained by multiplying all used flexibility (related to maximum intra-day swing) with its respective variable cost.

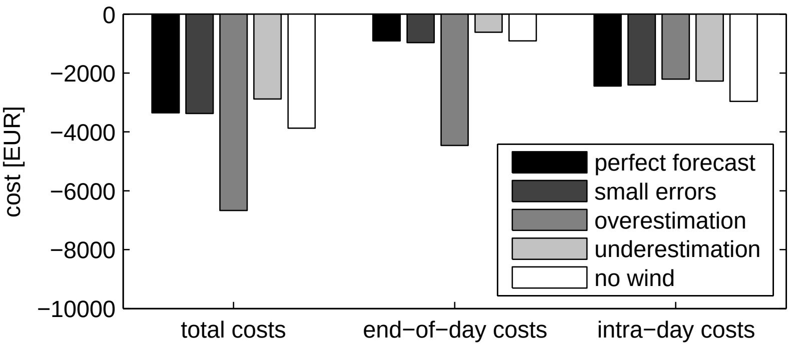


**Figure 5. System-balancing costs for one gas day (short historic shipper) – total costs are made up of intra-day balancing costs and end-of-day balancing costs; end-of-day costs are attributed to the unbalanced shippers, but intra-day costs are typically recovered outside the settlement mechanism, the relative division between the two cost-types depends on the variability and unpredictability of demand**

The balancing costs are more or less equal for all cases, except for the overestimation scenario, which has higher costs due to the dispatching of more expensive flexibility (see the merit order in Figure 4 for cost data and Table 4 for dispatching of flexibility). The balancing costs, then, are further broken down into “end-of-day costs” and “intra-day costs”. The former represent the costs of the end-of-day system imbalance, meaning the costs that can be associated with unpredictability of gas demand. If shippers can predict demand perfectly, these costs would be avoided. The intra-day costs, on the other hand, reflect the flexibility that is used to cover temporary imbalances that are corrected by the aggregated shippers before the end of the balancing period. Indeed, shippers can, e.g., inject gas in the line-pack buffer during the night to use it during the morning. As such, these costs relate to the variable nature of the gas demand and the inherent mismatch between demand and supply in the shipper portfolio. The difference between the perfect-forecast case and the no-wind case entirely comes down to differences in variability as the end-of-day system imbalances are equal. Whether the intra-day costs or the end-of-day costs are dominant, depends entirely on the time patterns of supply and demand and the *ex-ante* flexibility in the portfolio of the shipper. In the end, both costs are transferred to the shippers either as balancing charges for unbalanced shippers or partly socialized in the tariffs for all shippers.

**b. Historic shipper: long imbalance position**

Similarly, Figure 6 reports the net balancing costs for an example in which the historic shipper overshoots actual demand and commits too much gas, resulting in a long imbalance position.

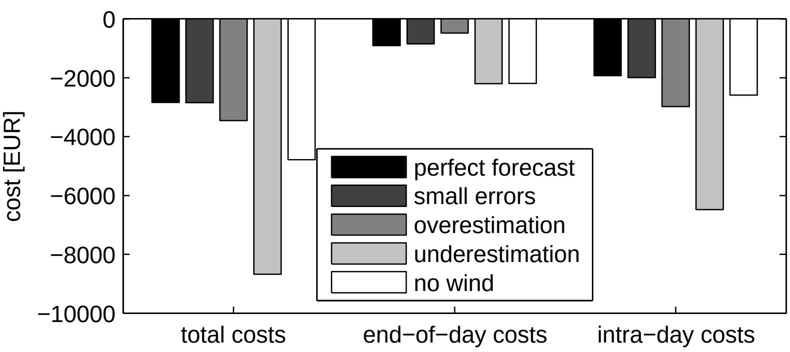


**Figure 6. System-balancing costs for one gas day (historic shipper is long) – total costs are made up of intra-day balancing costs and end-of-day balancing costs; end-of-day costs are attributed to the**

**unbalanced shippers, but intra-day costs are typically recovered outside the settlement mechanism, the division between the two cost-types depends on the variability and unpredictability of demand**

This time, the balancing costs of overestimating wind are not problematic because the opposing imbalance positions reduce the overall system imbalance, avoiding the dispatching of expensive flexible gas. The costs of balancing when the wind power is underestimated, on the other hand, have exploded because both shippers have committed too much gas, resulting in the injection of gas into more expensive underground storage (Table 5). In the other scenarios, the line-pack buffer provided sufficient flexibility to ensure gas-system integrity.

**Table 5. Dispatching of flexibility (daily net amount M.m$^3$) assuming a long historic shipper; positive: line-pack buffer / storage rises; negative: line-pack buffer / storage decreases**

| | Perfect forecast | Small error | Over-estimation | Under-estimation | No wind |
|---|---|---|---|---|---|
| Line pack [M.m$^3$] | 0.091 | 0.085 | -0.047 | 0.110 | 0.091 |
| Storage [M.m$^3$] | 0 | 0 | 0 | 0.133 | 0 |

Figure 7 shows the dynamically obtained merit order for the cases with a surplus for the historic shipper. The higher marginal costs of flexible gas in the underestimation case can be observed on the left-hand side. Note that system imbalances are long in four of the five cases because the historic shipper is now long.

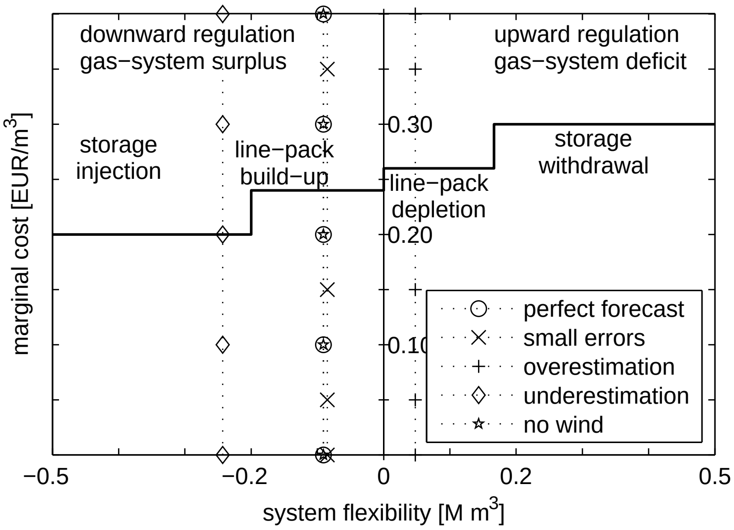


**Figure 7. Merit-order curve for system flexibility (historic shipper is long): upward (downward) regulation to correct gas system deficit (surplus), the system-imbalance lines determine the effective marginal cost of system flexibility. The "no-wind" and "perfect-forecast" lines overlap.**

### c. Conclusion on effect of wind unpredictability on physical balancing

Within the aim of this paper, more important than the actual numbers, which depend on assumptions and hypothetical data, are the qualitative effects that are observed. The physical impact on the gas network depends on the relative positions of the shippers. If both commit too much gas, the network buffer can become exhausted and the TSO has to turn to more expensive resources. Historic gas demand is well understood, making forecasting future demand easier. Residential demand, for instance, is temperature dependent, but rather than relying on the predicted temperature of just the next day, it is common practice in the gas industry to make heating-demand forecasts using an equivalent temperature that takes into account the predicted average temperature for the next day as well as average-temperature data of previous days.[6] By experience the shippers know the accuracy of that prediction method. The transfer of wind-power unpredictability and variability, on the other hand, is a new phenomenon.

The actually available line-pack flexibility depends strongly on the starting conditions. Therefore, unpredictability makes system management harder. Furthermore, end-state limitations for the next-day contingency also affect the use of line-pack flexibility and whether or not more expensive flexible gas has to be dispatched. The balancing costs were observed to depend strongly on the starting conditions. Indeed, in many simulations the system was able to deal with the imbalances using just line-pack flexibility. It should be noted, however, that the TSO takes preemptive actions based on the unit commitment submitted by the shippers. These anticipatory actions can be contrary to what would have been done if all information had been correct, e.g., increasing the buffer because shippers are expected to go short intra-day when in real time the shippers have committed too much gas, further inflating the buffer. The TSO can only act on the same information as the shippers and is thus subject to erratic information. These situations, where the unpredictability and the low-quality information affect both the shipper and the TSO, are challenging the balancing of the network.

Evidently, the identified dynamics have existed before the introduction of massive wind power. Indeed, in the no-wind scenario, it can be observed that line-pack flexibility covers the within-day variability of demand in the same way as the scenario with perfect forecasting of wind-power output. However, wind-power unpredictability that is transferred to the CCGT gas demand creates additional challenges for the gas-system balancing. Therefore, wind-power unpredictability has a strong impact on the physical balancing of the gas system and its flexibility tools. And this impact is likely to increase in the future.

### 3.2 Organizing imbalance settlement: regulatory options

Gas balancing occurs over a 24-hour interval in the EU and covers the actual gas dispatching. Balancing charges, then, are levied proportionally to the contribution of each individual shipper to the system imbalance. These balancing charges should be cost covering: either the total balancing costs or only the end-of-day costs that have been shown in Figure 5 and Figure 6. Balancing charges should also reflect actual costs and offer incentives to balance *ex ante*. First, a non-market-based design is examined, followed by a market-based design.

#### 3.2.1 Non-market-based settlement

In case of non-market-based settlement, shipper imbalances are typically settled against a price referring to the local or an adjacent spot market for gas. Additionally, a penalty term often provides an incentive for the shipper to balance *ex ante*. Appropriate penalty levels are derived below for an imposed TSO-cost-neutrality requirement with regard to balancing costs. Strictly speaking, a penalty is neither cost reflective nor meant to recover costs, even though it can "unintentionally" help recover costs. But in the context of the analysis of the present paper, the break-even penalties serve as mark-ups on the reference price to achieve cost neutrality. Thus, the TSO recovers the system-balancing costs from the unbalanced shippers and he defines a break-even mark-up on the reference price to achieve this goal. Balancing costs are discussed for different positions of the historic shipper, each time combined with the different forecast scenarios of the wind shipper.

**a. Historic shipper: short imbalance position**

Table 6 shows the break-even penalties for the cases with a small deficit for the historic shipper. This break-even penalty is calculated by dividing the applicable balancing cost (see Figure 5) by the imbalance basis and the reference gas price. This imbalance basis, then, is the sum of the absolute values of the individual shipper imbalances. It has been explained before that settlement mechanisms often do not make a distinction between

[6] This equivalent temperature is further linked to the degree-day concept that is frequently used in the heating sector as a measure for heating-services demand. The number of (equivalent) degree days is then obtained by subtracting the equivalent temperature from the predefined base temperature above which no heating is expected.

those who instigate the system imbalance and those who help the system with an opposite mitigating imbalance position. Therefore, both have to contribute to the recovery of the TSO's balancing costs.

**Table 6. Non-market-based imbalance tariffs: break-even penalty (expressed as a percentage of the reference gas price) to achieve cost neutrality with regard to the total balancing costs or only the end-of-day costs for the case of the short historic shipper**

| | Perfect forecast | Small error | Over-estimation | Under-estimation | No wind |
|---|---|---|---|---|---|
| Total balancing cost | 14.7% | 13.9% | 11.9% | 4.75% | 17% |
| End-of-day cost | 4% | 4% | 7.73% | 1.01% | 4% |

Intra-day costs are often socialized in the transmission tariff for all gas-network users. If that is the case, only the end-of-day balancing costs have to be recovered by means of the break-even penalty (second line in Table 6). The cost-neutral end-of-day penalties range between 1 percent and about 8 percent and are thus fairly low. If intra-day costs are not socialized, on the other hand, and all balancing costs have to be covered by a break-even penalty, this total penalty becomes two to four times as high as the end-of-day penalties, ranging from almost 5 percent till over 15 percent (first line in Table 6). A closer examination of the forecast scenarios reveals low penalty levels in the underestimation case. These particular levels are explained by the opposite imbalance positions of the historic shipper, who mitigates the system imbalance, and the wind shipper, who instigates the system imbalance. Their opposing positions reduce the aggregated system imbalance and lower balancing costs, on the one hand, and the imbalance basis is large because both shippers have an end-of-day imbalance, on the other hand. So, lower costs are divided over a larger imbalance basis; thus, requiring a small break-even penalty.

In the perfect-forecast and no-wind scenarios, the break-even penalties to recover total balancing costs are high compared to the scenarios with forecast errors. These high penalties indicate another problem of settlement design: in both scenarios the CCGT demand is perfectly predictable and the wind shipper balances over the day, resulting in an imbalance basis of zero. In other words, all balancing costs – including the intra-day costs caused by the wind shipper – are to be recovered from the historic shipper.

### b. Historic shipper: long imbalance position

Table 7 summarizes the break-even penalties for the examined forecast scenarios if the historic shipper has committed too much gas. The interpretation of the penalties is similar to that made in the preceding subsection: the first line of Table 7 represents mark-ups to pass on all balancing costs to unbalanced shippers, whereas the end-of-day penalties recover only the end-of-day costs while the intra-day costs are socialized.

**Table 7. Non-market-based imbalance tariffs: break-even penalty (expressed as a percentage of the reference gas price) to achieve cost neutrality with regard to the total balancing costs or only the end-of-day costs for the case of the long historic shipper**

| | Perfect forecast | Small error | Over-estimation | Under-estimation | No wind |
|---|---|---|---|---|---|
| Total balancing cost | 12.5% | 11.7% | 6% | 15.7% | 15.4% |
| End-of-day cost | 4% | 3.51% | 0.8% | 12.8% | 4% |

End-of-day penalties range from below 1 percent to over 12 percent depending on the forecast scenario. The mark-ups that cover all balancing costs vary from 6 percent to almost 16 percent. This spread is again explained by the dynamics of the imbalance basis and the actual balancing costs. E.g., in the underestimation scenario, both shippers instigate the system imbalance. Even though the imbalance basis is large, the dispatching of expensive flexibility (Table 5) increases balancing costs to such a degree that the end-of-day and the total break-even penalties become high compared to the respective penalties in the other forecast scenarios. The overestimation case in Table 7 is similar to the underestimation case in Table 6: both shippers have opposing and non-zero imbalances reducing balancing costs while both shippers are contributing to the recovery of those costs.

**c. Conclusion on effect of wind unpredictability on non-market-based settlement**

The difficulty in determining a proper break-even mark-up for non-market-based balancing mechanisms consists in ensuring the mark-up is high enough to pass on either the end-of-day costs, if intra-day costs are socialized, or the total balancing costs, if all costs are allocated to the unbalanced shippers. Yet, these balancing costs depend on unpredictable system imbalances. Thus, the *a-priori* determination of a mark-up that recovers and reflects costs is nearly impossible.[7] The varying penalties for the different forecast cases in, e.g., Table 6 illustrate this statement: in some scenarios a 1-percent mark-up is sufficient, whereas in other, equally likely cases a 7-percent mark-up is required to cover end-of-day costs.

Slightly overshooting the break-even level, though, can still be justified in order to provide balancing incentives to shippers. Indeed, cost-neutral penalties are not efficient in providing incentives. However, in current settlement mechanisms the single penalty level is fixed and independent of the actually used flexibility. More-unpredictable gas demand will result in more occurrences of the low-quality-forecast cases, leading to inappropriate penalty levels burdening shippers or failing to recover balancing costs.

A risk-averse system operator might be tempted to overshoot the break-even penalty rather than end up with an inadequately low mark-up. This might be the case for Belgium, where penalty levels of 40 percent of the reference price and higher are charged. Either the actual costs of system flexibility are very high, perhaps including some kind of (pipeline) capacity cost, or the penalty just serves as deterrence for shippers. Either way, the Belgian (and other countries') penalties are not transparent. For the shipper, on the other hand, a fixed penalty allows an easy comparison of the *ex-post* exposure to imbalance charges to the costs of *ex-ante* flexibility.

### 3.2.2 Market-based settlement

However, European TSOs are changing their settlement-mechanism design toward market-based settlement. This settlement mechanism implies that market dynamics determines the price of flexible gas. A merit-order curve for flexible gas offered to the TSO, e.g., Figure 4 or Figure 7, can be used for balancing and to derive imbalance tariffs from. The flexible gas is then acquired from balancing-services providers (in the framework of this chapter, it is irrelevant whether this is the TSO or other, competitive flexibility providers) who have to be paid an appropriate fee. The TSO, then, has multiple options to charge unbalanced shippers. One option consists of charging the average cost of these services. This is equivalent with the outcome of the cost-neutral penalties determined in the preceding section. Or, as a second option, the charges can be linked to the cost of the marginal unit of either upward or downward balancing energy.[8] Marginal-cost pricing of imbalances can result in profits for the TSO, but it can be more efficient as it provides better incentives to both the shippers and the TSO regarding flexibility needs. In the following subsections, this marginal-cost pricing is used as the pricing rule for *ex-post* balancing.

**a. Historic shipper: short imbalance position**

Table 8 summarizes the results of market-based settlement for the cases where the historic shipper is short. The upper two rows in Table 8 report the cost contributions (EUR) of the wind shipper and the historic

[7] It can be argued that cost recovery should not be accomplished on this very short term, but can be achieved, e.g., by charging a lump sum tariff (or tariff reduction) to all network users independent of the amount of used flexibility. However, such a lump sum fails to allocate costs to those causing them. Therefore, cost neutrality of the TSO should be achieved as close as possible to the balancing period because otherwise the link between cause (imbalance) and consequence (costs), or in other words, cost reflection is lost.

[8] Tariffs can be derived from the balancing merit-order curve in many different ways; the examples presented here are just two options that contain the principles of a market-based tariff.

shipper, respectively.[9] The final two rows in Table 8, then, display the degree of balancing-cost recovery (%) by the market-based charges, both with respect to the total balancing cost and the end-of-day cost. This degree, thus, indicates to what extent the balancing costs are passed on to the unbalanced shippers.

**Table 8.** ***Market-based imbalance tariffs (historic shipper has deficit): individual shipper contribution in terms of net balancing charges (EUR) and degree of balancing-cost recovery (%) of total market-based balancing charges***

| Cost contribution [EUR] and cost coverage [%] | Perfect forecast | Small error | Over-estimation | Under-estimation | No wind |
|---|---|---|---|---|---|
| Wind shipper | EUR 0 | EUR 58.7 | EUR 6936.3 | EUR 1520.7 | EUR 0 |
| Historic shipper | EUR 909.8 | EUR 909.8 | EUR 4549.2 | EUR 909.8 | EUR 909.8 |
| End-of-day cost | 100% | 100% | 259% | 398% | 100% |
| Total balancing cost | 27% | 29% | 168% | 84% | 24% |

Compared to the single penalty of a non-market-based mechanism, marginal-cost-based imbalance tariffs ensure full recovery of at least the end-of-day costs associated with unpredictability in all cases: cost coverage is 100 percent or above (third line in Table 8). Furthermore, the unbalanced shippers receive clear signals with reference to the cost of *ex-post* balancing: they pay substantially higher imbalance charges if the marginal cost of flexibility increases. This is the case for the overestimation scenario. Indeed, both short shippers are cashed out at the higher marginal cost of dispatched upward flexibility from storage (Table 4): the historic shipper pays about 4500 and the wind shipper almost 7000. For both shippers this amount is much more than the amount they pay in the other forecasts scenarios in which no expensive flexibility has been dispatched. The TSO even makes a profit as evidenced by the degree of cost coverage that is well above 100 percent for both recovery of end-of-day costs and recovery of total balancing costs. This profit can be used for the benefit of all network users by making investments in flexibility or by reducing the general transport tariffs that cover intra-day flexibility.

In the underestimation case, end-of-day unpredictability costs are also more than covered (398%), but the short historic shipper ends up paying for a system imbalance that he actually helped mitigate. If shippers are allowed to pool individual imbalances *ex post*, they can cooperate to reduce their exposure to balancing charges. For the TSO, on the other hand, such pooling would reduce the imbalance basis from which balancing costs can be recovered.

### b. Historic shipper: long imbalance position

Table 9 reports the imbalance charges for the historic shipper and the wind shipper, and the degree of cost recovery of end-of-day costs and total costs for the case of a long historic shipper. The shippers face the higher marginal cost of dispatched storage flexibility (Table 5) if they are both long. Again, efficient prices are charged to the unbalanced shippers and these prices cover at least the end-of-day imbalances. In some scenarios, also the total balancing cost is covered by the market-based charges, but this is not a structural result.

[9] Note that these values are costs for just 24 hours of balancing and that the comparison of the values between different forecast-cases is more important than the exact numbers.

**Table 9.** ***Market-based imbalance tariffs (historic shipper has surplus): individual shipper contribution in terms of net balancing charges (EUR) and degree of balancing-cost recovery (%) of total market-based balancing charges***

| Cost contribution [EUR] and cost coverage [%] | Perfect forecast | Small error | Over-estimation | Under-estimation | No wind |
|---|---|---|---|---|---|
| Wind shipper | EUR 0 | EUR 58.7 | EUR 1387.3 | EUR 7603.4 | EUR 0 |
| Historic shipper | EUR 909.8 | EUR 909.8 | EUR 909.8 | EUR 4549.2 | EUR 909.8 |
| End-of-day cost | 100% | 114% | 481% | 156% | 100% |
| Total balancing cost | 32% | 34% | 66% | 127% | 26% |

### c. Conclusion on effect of wind unpredictability on market-based settlement

If unpredictability increases, all shippers instigating larger system imbalances end up paying the high marginal cost of more expensive flexible gas; even if a shipper's contribution is limited. In the overestimation case of Table 8, the historic shipper's share of the system imbalance is about 33 percent and he pays about 4500 euro. But, if the wind shipper had avoided his massive forecasting error, the historic shipper would have paid about four times less as evidenced by the charges due by the historic shipper for the perfect-forecast and the overestimation case in Table 8.

Therefore, shippers with small imbalance positions of the same sign as the imbalances of dominant shippers dealing with massive unpredictability, such as gas demand related to intermittent wind power, are penalized by marginal-cost-based balancing because the small shipper pays a higher cost. And this cost is actually caused by the dominant shipper. The actions of such dominant shippers affect the price of flexibility and the assumption of price-taking shippers no longer holds.

Another peculiarity that has been observed in some simulations is the dispatching of expensive upward intra-day flexibility when the end-of-day imbalances of the system and the shippers were all positive. In that case, the shippers would only pay the marginal cost of downward flexibility instead of the expensive upward flexibility. This anomaly is dependent on the design of the settlement mechanism and can be remedied by making a distinction between those instigating and those mitigating the system imbalance at the time of the dispatching of expensive flexibility, or by reducing the balancing interval (e.g. hourly or every quarter-day) to better allocate costs.

## 4. Summary and conclusions

This paper has studied the possible implications of the transfer of wind-intermittency into the gas system. This organizational and regulatory challenge of interacting energy systems seems to be somewhat overlooked as evidenced by the limited availability of academic and industry literature on the topic. Yet, it is important for policy makers and regulators to be aware of transferred externalities, to be able to design adequate rules for both the electricity and gas system, which will interact more and more in the next decades.

This impact of unpredictability of RES on gas balancing has been investigated by applying the electricity-generation concepts of "unit commitment", "power dispatching" and "forecasting error" to the gas balancing problem and using operations research to simulate the optimal operation of a gas system. Physically, the network flexibility and flexible gas need to cover potentially very large deviations of several percent of the (scaled) demand due to forecast errors in the commitment phase compared to the actual dispatching of gas. System flexibility has to cover this imbalance, with increasing unpredictability leading to the dispatch of more expensive flexible gas to cover the physical swing. Therefore, unpredictability raises the costs of system balancing. These results confirm earlier findings in the literature.

The organizational impact regarding the financial settlement of imbalances and the allocation of costs is closely related to the increased physical swing: large prediction errors cause large gas-system imbalances, requiring more expensive flexible gas in a market-based-balancing framework. Such a balancing mechanism provides clear incentives to balance the system *ex ante* because the more unbalanced the system, the less favorable the *ex-post* balancing charges become. The downside of this mechanism is a risk that massive uncontrollable and unpredictable wind increases gas-system imbalances and thus deteriorates the balancing conditions for all other users, who cannot be held responsible for the gas matching problems of the wind shipper. Indeed, as has been demonstrated in the analysis of this paper, dominant shippers with an unpredictable portfolio could become price setters instead of price takers. Hence, market-based settlement in a gas market with large shippers with unpredictable portfolios leads to higher costs for other network users who are not or less responsible for these costs.

The simulations have further demonstrated that a non-market-based settlement, which is currently the main design in Europe, is not really affected by the transfer of unpredictability because this kind of system is to a large extent independent of gas-balancing dynamics.[10] Yet, the main difficulty consists of determining an appropriate fixed penalty that results in passing on balancing costs and at the same time does not harm shippers by being excessive. Indeed, cost-neutral recovery of costs would require the penalty to change frequently, whereas this penalty is actually defined within the balancing rules beforehand.

Furthermore, both organizational designs of settlement fail to recover the full cost of balancing, meaning the costs associated with intra-day and end-of-day imbalances. Indeed, the intra-day costs are absorbed by the TSO and socialized by means of the general transport tariffs, confirming the findings of [11]. Better and more efficient cost allocation is achieved if shorter balancing intervals are used. To summarize, from a regulatory point of view, it is clear that the gas system is impacted by the transfer of intermittency. This has been demonstrated in this paper with regard to the physical balancing of the gas system specifically focusing on the settlement of imbalances afterwards.

The analysis presented here is an *a posteriori* study of the impact of wind power on gas. Other methods should be applied to make an *a priori* assessment taking into account interactions between the gas actors, especially in the market-based case. This would require another class of models: equilibrium modeling. Evidently, real balancing designs are substantially more complex and try to remedy some of the fallacies of simple designs, but the main findings are general enough to hold because complex designs still use the basic building blocks. For instance, the addition of *ex-ante* flexibility would allow the shipper to modulate demand and reduce imbalances, but prediction errors would still be present on a very short term.
Furthermore, the study in this paper is the first to explicitly associate the challenges of designing gas-balancing mechanisms to the issue of wind-power integration, or more in general, increasing unpredictability of gas demand. It provides a first step in a field where further research is needed to streamline the operation of future closely interconnected electricity-and-gas systems. Actual case studies will provide further insight in the size of the effects transferred from electricity to gas. These are subject of further research.

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## Appendix: technical gas-network data

**Table 10. Nodal information for network of Figure 3: nodal-pressure limits, presence of compression and the maximal compression ratio and function of node in network**

| Node | Pressure limits (low/high) [bar] | Compression (y/n) | Function: demand (D), supply (S), transit (T), upward flexibility (F+) or downward flexibility (F-) |
|---|---|---|---|
| Supply A | 60 / 80 | n | S |
| Supply B | 60 / 80 | n | S |
| CCGT1 | 60 / 80 | n | D |
| CCGT2 | 60 / 80 | n | D |
| CCGT3 | 60 / 80 | n | D |
| CCGT4 | 60 / 80 | n | D |
| Industry | 60 / 80 | n | D |
| Storage | 60 / 80 | n | F+/F- |

**Table 11. Pipelines of Figure 3: diameter D, distance L and range of starting average pressures $\bar{p}_{a(ij),start}$ to determine line pack**

| Pipeline | D [m] | L [km] | $\bar{p}_{a(ij),start}$ [bar][a] |
|---|---|---|---|
| Supply A – CCGT1 | 0.7 | 30 | 62 - 70 |
| Supply A – CCGT2 | 0.7 | 30 | 62 - 70 |
| CCGT2 - Storage | 0.7 | 7.5 | 62 - 70 |
| CCGT2 – Industry | 0.7 | 15 | 62 - 70 |
| Industry – CCGT3 | 0.7 | 15 | 62 - 70 |
| CCGT3 – CCGT4 | 0.7 | 30 | 62 - 70 |
| Supply B – CCGT3 | 0.7 | 30 | 62 - 70 |

[a] a range of starting average pressures is tested, the reported cases use 62.5 bar (short historic shipper) and 70 bar (long historic) shipper

**Table 12. Storage details for network of Figure 3: base gas that remains in storage, working-gas capacity that can be filled and emptied and injection and withdrawal limits**

| Node | Base gas [M.m$^3$] | Working gas [M.m$^3$] | Injection limit [M.m$^3$/h] | Withdrawal limit [M.m$^3$/h] |
|---|---|---|---|---|
| Storage | 39 | 117 | 0.85 | 1.1 |